**STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS**
**PUBLIC UTILITIES COMMISSION**

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| **IN RE: THE NARRAGANSETT** | **:** | |
| **ELECTRIC COMPANY** | **:** | |
| **d/b/a NATIONAL GRID** | **:** | |
| **GAS COST RECOVERY CHARGE** | **:** | **DOCKET NO. 4576** |

# REPORT AND ORDER

## I. NATIONAL GRID'S FILING

On September 1, 2015, The Narragansett Electric Company d/b/a National Grid (National Grid or Company) submitted its Gas Cost Recovery (GCR) filing to the Public Utilities Commission (PUC or Commission). The GCR is an annual filing that allows National Grid to reconcile and recover its estimated costs for gas supplies, including pipeline transportation and storage charges, for the GCR year beginning November 1. The instant filing proposed a decrease in rates approved by the PUC earlier, in Docket No. 4520, for the period November 1, 2015 through October 31, 2016. The proposed rates realize an annual decrease of approximately $120.54 for a typical residential heating customer using the equivalent of 846 therms per year.

In support of its filing, National Grid submitted the prefiled testimonies[1] of Elizabeth D. Arangio, Director of Gas Supply Planning for National Grid; Ann E. Leary, Manager of Gas Pricing for National Grid USA Service Company, Inc.; Theodore E. Poe, Jr., Manager of Gas Load Forecasting and Analysis; and Stephen A. McCauley, Director of Origination and Price Volatility Management in the Energy Procurement organization of National Grid USA Service Company, Inc. Ms. Arangio's testimony provided support

[1] Prefiled testimony is available at the Commission offices located at 89 Jefferson Boulevard, Warwick, Rhode Island or at www.ripuc.org/eventsactions/4520page.html.

for the estimated gas costs, assignment of pipeline capacity to marketers, other issues relating to the Company's proposed factors, and a summary of National Grid's decision to enter into a Precedent Agreement with Tennessee Gas Pipeline Company, LLC (Tennessee) for interstate pipeline capacity delivered to the state as part of the Tennessee Northeast Energy Direct Project (NED).[2] She explained that the proposed GCR factors are based on the New York Mercantile Exchange (NYMEX) strip as of the close of trading on July 31, 2015 and the difference between the futures contract purchases under the Gas Procurement Incentive Plan (GPIP) as of July 31, 2015 and the July 31, 2015 NYMEX strip. The factors also reflect storage and inventory costs as of July 31, 2015 and the projected cost of purchasing gas ratably through the injection season as provided for in the Natural Gas Portfolio Management Plan (NGPMP). She noted that this year's average NYMEX pricing is lower than it was last year.[3]

Ms. Arangio described how the Company uses a SENDOUT model to calculate projected gas costs. To minimize yearly supply costs, pricing, contract, and storage information are used to determine the dispatch of supplies.[4] Ms. Arangio explained the two gas cost components for the GCR: (1) Supply Fixed Costs, which include purchase, storage, or delivery of firm gas including pipeline and supplier fixed reservation costs, demand charges, and transportation fees; and (2) Supply Variable Costs, which include commodity costs, taxes on commodity, other gas supply expenses incurred to transport and store the gas, and inventory commodity costs.[5] Attached to her testimony, Ms.

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[2] Arangio Direct at 3 (Sept. 2, 2015).
[3] *Id.* at 4.
[4] *Id.* at 5.
[5] *Id.* at 5-6.

Arangio provided supporting detail for the gas costs.[6] She described how the Company calculates the delivered cost for a particular gas supply. Beginning with the NYMEX price, the amount is then adjusted for basis differential and to reflect fuel retention, and finally, the cost of transportation on the pipeline is added.[7]

Ms. Arangio explained that National Grid will continue to operate its portfolio similar to how it operated last year. She described the Company's various contracts and its plans to supply the East-West Capacity for 2015-2016.[8] She also provided that National Grid entered into an arrangement for liquid service for the 2015 off-peak refill season and expects to have its LNG facilities 100% full as of December 2015.[9]

Ms. Arangio identified steps that the Company had taken to address long-term portfolio risks. The first step was to participate in the Algonquin Incremental Market Expansion (AIM Project) and to execute a Precedent Agreement with Tennessee for its NED project.[10] The second step was to execute agreements with GDF Suez and Gaz Metropolitan to address the Company's short-term LNG needs and to continue participation in the LNG Consortium with New England distribution companies and municipally-run companies to find sources of LNG and balance supply with price and delivery sources. National Grid was and is also pursuing its own liquefaction opportunities.[11]

Ms. Arangio provided an overview of the AIM Project noting it is expected to be in service by November 2016. She also described the NED project, which is expected to

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[6] *Id.* at EDA-2.
[7] *Id.* at 7-8.
[8] *Id.* at 8-15.
[9] *Id.* at 15.
[10] *Id.* at 16.
[11] *Id.* at 16-19.

be in service by November 2018, as an expansion of the existing Tennessee system. It will, she explained, involve additional pipeline, market delivery lateral and loops, city gates, and new and modified compressor stations. She noted that National Grid entered into a 20 year Precedent Agreement beginning on the in-service date, the rate of which includes costs associated with providing incremental service to all of the Company's existing citygates.[12]

Regarding marketer capacity assignment, Ms. Arangio represented that the Company has made available to marketers 32,758 decatherms (Dth) per day of capacity on six different pipeline paths. She explained the calculation of the surcharge/credit for each assigned pipeline path and the calculations of the delivered costs for each path released to marketers. She added a Fixed Unit Cost of $0.5925 per Dth to the system average pipeline unit variable cost of -$0.1763 per Dth to derive the $0.4162 per Dth weighted average pipeline cost. She then added the weighted average pipeline cost to the 100% load factor per unit cost of $0.0057 for the marketer reconciliation adjustment to average pipeline cost of $0.4219 per Dth. She also explained the calculation for the delivered cost for each path.[13] Lastly, Ms. Arangio provided that the Company had filed a proposal for changes to its Customer Choice Program.[14]

Ms. Leary provided testimony to propose GCR factors for firm sales service and transportation service.[15] She explained that the proposed GCR factors are load specific, High Load and Low Load, and necessary for the Company to be able to recover the projected gas costs allocated to its firm sales customers for the November 1, 2015

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[12] *Id.* at 19-20.
[13] *Id.* at 21-23, Attach. EDA-4.
[14] *Id.* at 23.
[15] Leary Direct at 2 (Sept. 2, 2015).

through October 31, 2016 period. For the twelve-month period ending October 31, 2016, Ms. Leary stated projected gas costs for the Company's firm sales customers would be approximately $134.3 million. She identified a number of other costs and credits that, when added to the costs for the firm sales customers, would total $142.1 million in net costs necessary for the Company to collect.[16]

Ms. Leary related that the Fixed Cost component includes all Fixed Costs related to the purchase, storage, and delivery of firm gas for both High and Low Load factor customers. She explained the derivation of the component that resulted in total Fixed Costs of $30.7 million to be allocated to and collected from ratepayers based on their proportion of design-winter use requirements. She provided that the GCR factors were determined by dividing the allocated fixed gas cost by the projected throughput for each group, the High Load group and the Low Load group. She proposed a GCR Fixed Low Load factor of $1.1469 per Dth and a GCR Fixed High Load factor of $0.8833 per Dth.[17]

Ms. Leary noted that the Company agreed previously to provide an annual reconciliation of Marketer Fixed Costs and described the calculation of the Marketer Fixed Cost Reconciliation Balance, which she stated updated the 2014/2015 pipeline surcharge/credit for each path using actual pipeline capacity costs resulting in a Marketer surcharge of $39,670. She stated that the 2013/2014 Marketer reconciliation filed last year was updated to replace forecasted capacity and revenues with actual capacity and revenues resulting in a Marketer surcharge of $28,028. She identified a net surcharge to Marketers of $58,533 that would be credited to firm sales customers' fixed charges and

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[16] *Id.* at 3-4.
[17] *Id.* at 5-6.

included in the 2015-2016 pipeline surcharge/credits set forth by Ms. Arangio.[18] She stated that the monthly design sales forecast was calculated using a monthly specific heat factor as opposed to using a seasonal heat factor as it did last year.[19]

In describing the Variable Cost component, Ms. Leary identified total Variable Costs as covering all Variable Costs of gas, including commodity costs, supply-related LNG operation and maintenance, working capital, inventory finance costs, pipeline refunds, and deferred cost balances. She calculated Variable Costs for the November 2015 through October 2016 period to be $111,456,578. She divided that number by the projected period throughput of 27,009,852 Dths to reach a Variable Cost factor of $4.1265 per Dth.[20] She asserted that an estimated deferred balance under-collection of $8,227,655 at October 31, 2015 is incorporated into the GCR rate as well as the projected deferred gas cost balances for the November 2015 through October 2016 period.[21]

Ms. Leary provided that the Company was also proposing changes to the GCR deferral balance for the period April 2014 through March 2015, filed with the Commission on June 30, 2015, to include $23,399 in curtailment penalty charges that were incurred by Non-Firm customers and omitted from Non-Firm gas costs. She presented a proposed FT-2 marketer demand rate of $8.8817 per Maximum Daily Quantity (MDQ) in Dth/month and the Storage and Peaking charge of $0.0694 per therm for FT-1 firm transportation customers returning to Transitional Sales Service. She also submitted capacity assignment percentages for the High Load and Low Load factors to be

[18] *Id.* at 6-7.
[19] *Id.* at 8.
[20] *Id.* at 8-9.
[21] *Id.* at 9, Attach. AEL-1, AEL-3.

used in the determination of pipeline, underground storage, and peaking capacity for Marketers.[22]

Ms. Leary explained why the Company experienced negative monthly sales for April 2014 through March 2015 and identified the four billing adjustments that resulted in the negative sales reporting. Specifically, the four billing adjustments all involved Extra Large High Load factor customers and either the reclassification of those customers' service or a correction in the amount of dekatherms billed. Ms. Leary noted that the GCR revenues will reflect the correct revenue since the cancellation and rebilling of these customers' accounts are based on rates at the time of usage.[23] Finally, Ms. Leary identified an approximate $120.54 annual reduction to a residential customer using 846 therms per year resulting from the proposed rates.[24]

Mr. Poe provided testimony to support the Company's natural gas requirements forecast used to estimate its gas costs. He explained that every April 1, the Company utilizes a five-step process to determine its ten-year forecast of customer requirements. He provided that the volume forecast consists of the meter count and use-per-customer at the rate class level. The retail forecast also takes into account the impact of the Company's energy efficiency programs.[25] After determining the retail forecast, Mr. Poe explained that it is adjusted for billing lag and unaccounted-for-gas to determine the wholesale forecast. Both the retail and wholesale forecasts are used by the Company for supply, engineering, and financial planning.[26]

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[22] *Id.* at 10, Attach. AEL-5, AEL-6.
[23] *Id.* at 11-15.
[24] *Id.* at 10-13.
[25] Poe Direct at 2-4 (Sept. 2, 2015).
[26] *Id.* at 4.

Mr. Poe related that this year's retail forecast of 39,897,041 MMBtu reveals a 4.7% increase over last year's total retail forecast. This was so even though the residential sales forecast was slightly lower due to the sluggish housing market which he represented Moody's expects to turnaround in the second half of the year. He identified a total wholesale sales volume growth rate of 4.2%.[27]

Mr. McCauley discussed the results of the Gas Procurement Incentive Plan (GPIP)[28] for the period July 1, 2014 through June 30, 2105 and the results of the Natural Gas Portfolio Management Plan (NGPMP) for April 1, 2014 through March 31, 2015.[29] The GPIP incentive or penalty is determined by multiplying the total savings or cost by 10%. The total savings is multiplied by 20%, however, for those discretionary purchases made at least eight months prior to the month of gas flow where the unit cost savings is greater than fifty cents per dekatherm or by 5% for any discretionary purchases made during the four months prior to the month of flow.[30] The Company calculated an $84,340 incentive, which Mr. McCauley proposed be granted in full. He also discussed the Company's request and the Commission's approval to include in the GPIP locational basis hedges for supplies purchased in the Marcellus production area. He noted that currently pending with this PUC was another proposal to execute Market Area locational basis hedges for the November 2015 through March 2016 period similar to those previously approved.[31]

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[27] *Id.* at 5-6.
[28] The Gas Procurement Incentive Plan encourages the Company to purchase supply in a way that will stabilize supply and reduce the risk of extreme price escalation. It requires National Grid to lock in future gas prices over a 24-month horizon and that these purchases are made in a structured series of monthly increments. The difference between the average unit cost of the mandatory hedges and the average unit cost of discretionary purchases is multiplied by the discretionary volumes to calculate total savings or cost.
[29] McCauley Direct at 2 (Sept. 2, 2015).
[30] *Id.* at 3-4.
[31] The Commission approved this request at an open meeting on September 22, 2015.

Mr. McCauley described the NGPMP, which shifted management of the Company's gas portfolio from an external company to internally within National Grid. He opined that internal management is superior to the previous external management arrangement because it reduces the potential for performance failure by an external manager. Moreover, savings realized are greater than those realized with a third party manager. Noting that the NGPMP is currently in its fifth year,[32] Mr. McCauley said it has saved the Company approximately $11.5 million. He noted that the program will pass approximately $9.4 million of those savings on to customers. The Company received 20% of the total of savings in excess of $1 million or $2,109,531.34 for the April 2014 through March 2015 period.[33] Mr. McCauley noted that the Company does not include any revenue from Asset Management Agreements in the incentive and is not proposing any changes to the NGPMP incentive at the current time. He requested, on behalf of the Company, that the quarterly reporting due date be changed from the 25th day of the month after the end of each quarter to the first business day of the second month following the end of the quarter. This requested change would allow for a little extra time after the final accounting numbers are received after the 20th of each month.[34]

## II. DIVISION OF PUBLIC UTILITIES AND CARRIERS' FILING

To address National Grid's filing, the Division of Public Utilities and Carriers (Division) submitted the testimony of Bruce R. Oliver, its consultant. Mr. Oliver observed that the more than 20% reduction in GCR charges is due primarily to the elimination of the large under-collection that occurred during the winter of 2013-2014. He recommended acceptance of both the GPIP and NGPMP incentives as well as the

[32] The Commission approved the NGPMP in Docket No. 4038, Order No. 19627 on March 31, 2009.
[33] McCauley Direct at 6-7, Attach. SAM-3 (Sept. 2, 2015).
[34] *Id.* at 7.

other charges proposed by the Company. As he did last year, he expressed concern with the Company's forecasts of sales and throughput volumes, as well as the Company's forecasted monthly distribution of gas use by rate classification. Mr. Oliver also suggested that the Commission undertake a more comprehensive review of National Grid's plans for adding long-term pipeline capacity and LNG Liquefaction capacity. He further recommended that review of the Company's 10-year forecast of gas supply requirements also consider the impacts of the Customer Choice Program and the Company's proposal to allow the return of capacity-exempt customers.[35]

Mr. Oliver noted that this is the third year since total gas costs have declined from the prior year's projections. He identified the specific factors that account for the difference between the decline and the proposed reductions in firm sales customer charges.[36] He described how the Company prices the pipeline capacity and storage and peaking capacity that it assigns to marketers for use in serving Transportation service customers. He also explained how it calculates the charge to marketers for assignment of pipeline capacity.[37] He provided that the proposed charges for marketers' use of assigned pipeline capacity and for storage and peaking capacity were reasonable.[38]

Mr. Oliver asserted that after review of the Company's reconciliations, he found them reasonable and accurate. He noted the aggregate deferred gas cost balance as of March 31, 2015 was $22,413,764 and that between then and September 18, 2015 the balance was reduced to $9,149,232. He suggested further investigation was warranted concerning the large deviations between the Company's forecasted and actual average

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[35] Oliver Direct at 1-4 (Oct. 16, 2015).
[36] *Id.* at 6-7.
[37] *Id.* at 9-10.
[38] I*d.* at 13.

costs per Dth.[39] Stating that the GPIP continues to benefit ratepayers, he recommended approval of the $84,340 incentive requested by the Company. After describing the NGPMP and noting that this year customers received the highest benefit to date, $9.4 million, he recommended approval of the $2,109,531.34 incentive to the Company.[40]

Mr. Oliver spent a large portion of his prefiled testimony discussing National Grid's sales forecasting methods and questioning their accuracy. However, his concern did not alter his recommendation that the Commission accept the GCR charges as proposed.[41]

## III. NATIONAL GRID'S REPLY COMMENTS

In response to Mr. Oliver's direct testimony, National Grid filed reply comments on October 20, 2015. In those comments, National Grid asserted that Mr. Oliver's allegations regarding the Company's forecasting did not substantially affect the tariff computations, and accordingly requested that the Commission approve the proposed GCR charges that Mr. Oliver agreed were reasonable.[42]

## IV. DIVISION OF PUBLIC UTILITIES AND CARRIERS RESPONSE

Immediately prior to the start of the hearing on October 26, 2015, the Division provided reply comments to the Company's October 20, 2015 comments. Mr. Oliver reiterated and further elaborated on his forecasting concerns. He conceded that his recommendation to accept the Company's proposed GCR rates was not dependent on acceptance of the Company's forecasts.[43]

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[39] *Id.* at 15-17.
[40] *Id.* at 18-22.
[41] *Id.* at 3, 22-46.
[42] National Grid Reply Comments at 1-8 (Oct. 20, 2015).
[43] Oliver Response at 1-18 (Oct. 26, 2015)

## HEARING

At the hearing on October 26, 2015, the Chairperson granted National Grid's Motions for Protective Treatment[44] and, after ensuring no objection, all exhibits were marked as full exhibits.[45] Prior to presentation of the Company's witnesses, Mr. Adam Ramos, counsel for National Grid, remarked that the Company and the Division agreed that Mr. Oliver's concerns regarding forecasting did not impact his recommendation to approve the proposed GCR factors. He noted that the Company agreed to work with the Division to address Mr. Oliver's concerns and mutually agree on a forecasting methodology going forward.[46] Jennifer Brooks-Hutchinson, co-counsel for National Grid, set forth the specific factors and amounts requested. She noted that the amounts requested in combination with the Distribution Adjustment Clause factors result in an annual decrease to an average residential heating customer using 846 therms of $110.93 from rates currently in effect, or an 8.9% increase.[47]

National Grid presented Ms. Arangio, Ms. Leary, Mr. McCauley, and Mr. Poe as a panel. All of the witnesses adopted their prefiled testimony.[48] Ms. Arangio testified that the GCR rates are intended to collect $134.3 million in gas costs that the Company is projecting for the 2015/2016 season.[49] Mr. Poe acknowledged that the Company and the Division would work together to address Mr. Oliver's forecasting concerns. He testified that the process would include periodic reports to the Commission.[50] Ms. Arangio updated the Commission on the AIM and the Tennessee NED projects and their

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[44] Hr'g Tr. 5-7.
[45] *Id.* at 4-5.
[46] *Id.* at 7-9.
[47] *Id.* at 10-11.
[48] *Id.* at 13-22.
[49] *Id.* at 33-34.
[50] *Id.* at 35-36.

anticipated in -service dates of November 2016 and November 2018, respectively. She also discussed the two liquefaction projects. She noted that neither of the projects has been filed with FERC but both are anticipated to be in service by the summer and fall of 2018.[51] She noted that the Company has contractual commitments for the AIM project and a conditional commitment for the NED project.[52]

Ms. Leary explained the 2014 move of approximately 2,600 non-heating customers to the heating rate. Mr. Poe further explained the month-to-month variations in forecasting for the winter season. Ms. Leary added that this year the Company computed a monthly heat factor for each month as opposed to last year where the Company used a seasonal heat factor.[53] When questioned about the more than $2 million increase in the deferred gas cost balance in the past six weeks, Ms. Leary explained that sales revenues were down and some gas prices were slightly higher than what the Company had forecasted.[54]

The Division presented Mr. Oliver who testified that he was satisfied the GPIP and NGPMP incentives requested by the Company conformed with the terms of the programs.[55] Mr. Oliver remarked that a better understanding of the Company's forecasts and the fluctuations in the through-put volumes for certain classes' sales is necessary. He opined that the issue involves capacity and how much is needed for long term planning when the Company is considering projects like the AIM and NED projects.[56] He expressed that while the Company has stated it has not changed its forecasting

[51] *Id.* at 36-38.
[52] *Id.* at 38-39.
[53] *Id.* at 40-43.
[54] *Id.* at 44-45.
[55] *Id.* at 51.
[56] *Id.* at 51-54.

methodology, the changes in forecasts are too significant to be left without explanation.[57] When asked, Mr. Ramos informed the Commission that the Company would move expeditiously to address the forecasting issue.[58]

## COMMISSION FINDINGS

At an Open Meeting on October 30, 2015, the Commission approved a High Load GCR Charge of $0.5259 per therm for Residential Non-Heating, Large High Load, and Extra Large High Load classes. It approved a Low Load GCR Charge of $0.5530 per therm for Residential Heating, Small Commercial and Industrial, Medium Commercial and Industrial, Large Low Load, and Extra Large Low Load classes. Additionally, the PUC approved an FT-2 Marketer Demand charge of $8.8817 per dekatherm per month, a Storage and peaking charge for FT-1 Transportation customers of $0.6945 per Dekatherm and a weighted average system capacity charge of $0.4219 per dekatherm of capacity for usage on and after November 1, 2015.

The Commission found the Company's request for the $84,340 incentive on its GPIP and the NGPMP incentive of $2,109,531.34 to be fair and reasonable and approved the same. It also approved the Company's request to continue the NGPMP for another year. Additionally, the Commission found reasonable and approved National Grid's request to extend the date required to file its NGPMP quarterly reports from the 25th day of the month following the end of the quarter to the first business day of the second month following the end of the quarter. As previously held, the Company shall not be allowed to earn an incentive on its third-party asset management agreements. Finally, the PUC approved the BTU Conversion Factor of 1.031. The Commission is satisfied that

[57] *Id.* at 54-55.
[58] *Id.* at 60-61.

the rates proposed by National Grid and supported by the Division were properly calculated and will ensure that customers pay a just and reasonable rate.

Accordingly, it is

(22242) ORDERED:

1. The Gas Cost Recovery factors of:
   a. $0.5259 per therm for Residential Non-Heating customers, Large High Load, and Extra Large High Load Factor customers, and
   b. $0.5530 per therm for Residential Heating customers, Small Commercial and Industrial, Medium Commercial and Industrial, Large Low Load, and Extra Large Low Load Factor customers

   are approved for usage on and after November 1, 2015.
2. A Weighted Average System Capacity Charge of $0.4219 per dekatherm is approved for usage on and after November 1, 2015.
3. The Gas Marketer Transportation factors of:
   a. $8.8817 per dekatherm for the FT-2 Firm Transportation Marketer Gas Charge, and
   b. $0.6945 per dekatherm for a Storage and Peaking Charge

   are approved for usage on and after November 1, 2015.
4. The incentive of $2,109,531.34 for the Natural Gas Portfolio Management Plan is approved.
5. The incentive of $84,340 for the Gas Procurement Incentive Plan is approved.
6. The Company shall file its Annual Gas Cost Recovery Reconciliation by July 1 of each year.

7. The BTU factor of 1.031 is approved.
8. National Grid shall provide electronic versions of all spreadsheets at the time of its initial filing.
9. National Grid shall comply with the reporting requirements and all other findings and directives contained in this Report and Order.

EFFECTIVE NOVEMBER 1, 2015 IN WARWICK, RHODE ISLAND PURSUANT TO AN OPEN MEETING DECISION ON OCTOBER 30, 2015. WRITTEN ORDER ISSUED NOVEMBER 30, 2015.

PUBLIC UTILITIES COMMISSION

Margaret E. Curran, Chairperson

Paul J. Roberti, Commissioner

Herbert F. DeSimone, Jr., Commissioner

**Notice of Right of Appeal**: Pursuant to R.I. Gen. Laws § 39-5-1, any person aggrieved by a decision or order of the PUC may, within 7 days from the date of the Order, petition the Supreme Court for a Writ of Certiorari to review the legality and reasonableness of the decision or Order.